MEMORANDUM

TO: James Mundt, Director
Office of Fiscal and Management Analysis, Legislative Services Agency

FROM: Janet McCabe, Assistant Commissioner
Office of Air Management

DATE: December 22, 2000

SUBJECT: Analysis of Fiscal Impact of New Rules Concerning Emissions of Nitrogen Oxides (NOx); LSA #00-137

The Department of Environmental Management (IDEM) is submitting these draft rules for your economic impact analysis under IC 4-22-2-28, IC 13-14-9-5, and IC 13-14-9-6. The following information is provided for your analysis:

1. The second notice of comment period which contains the draft rule published in the Indiana Register on December 1, 2000.
2. The fiscal impact memo submitted to the State Budget Agency.
3. The Projected Impacts of NOx Emissions Reductions on Electricity Prices in Indiana, State Utility Forecasting Group, Purdue University, June 2000.

SUMMARY: These draft rules require reductions of nitrogen oxides from cement kilns, electricity generating units, and large industrial boilers. They apply to 23 facilities in Indiana. The costs of this rule included capital costs for installation of control equipment, ongoing operation and maintenance costs, and costs of monitoring compliance.

As described in this analysis, overall costs are conservatively estimated as follows:

Total capital costs: $1,420 M to $1,423 M
Total ozone season costs: $265.7 M to $266.2 M

Overall cost effectiveness: $2,226 to $2,231 per ton of NOx removed.

The bulk of the costs will be incurred by the electric utility industry. The cost effectiveness of the program is enhanced by the inclusion of a multi-state trading program, which will encourage implementation of the least costly control programs. Electric rates for residential, commercial, and industrial customers are predicted to increase by 6 to 7 percent or $0.0033 per kilowatt hour.

I. Background

On September 24, 1998, U. S. EPA issued a rule (NOx SIP call) that required each of twenty-two (22) states in the eastern United States, including Indiana, to reduce its emission of nitrogen oxides by 2007. Although the federal rule does not mandate how states are to reduce nitrogen oxide (NOx) emissions and meet the federally established “budget”, U. S. EPA based its calculation of each state’s budget on a determination of what it believed to be cost-effective NOx reductions. The source categories identified by U. S. EPA were electric utility boilers, large industrial boilers, cement kilns, and stationary internal combustion engines. The federal rule is intended to reduce the transport of ozone and ozone causing pollutants that occurs in this multi-state region. A number of parties challenged the legality of the rule in the U. S. Court of Appeals for the D. C. Circuit. The court upheld U. S. EPA’s actions for the most part, although it directed U. S. EPA to revisit the establishment of the control requirements for internal stationary combustion engines and revise the number of states that will be required to respond to the NOx SIP call. The court also extended the compliance date for the SIP call to May 31, 2004.

These Indiana draft rules regulate electricity generating units with a nameplate capacity greater than twenty-five (25) megawatts, industrial, commercial and institutional steam generating units that have a heat input capacity greater than two hundred fifty million (250,000,000) British thermal units (Btu) per hour and certain cement kilns. It requires these facilities to reduce nitrogen oxide emissions during the period May 31 through September 30 in 2004 and May 1 through September 30 thereafter. However, sources can receive a one year extension in the compliance date upon showing that they have reduced NOx emissions prior to May 1, 2004.

The draft rules included with this analysis are largely based on the federal NOx SIP call rule. They include emission reduction requirements for cement kilns and the U. S. EPA’s model trading program that affects electric generating units and large industrial boilers. The emission reductions required by these draft rules meet the targets required by U. S. EPA in the SIP call. They will result in a reduction of one hundred eighteen thousand one hundred eighty-three (118,183) tons state wide by 2007. This is approximately a thirty-one (31%) reduction from what statewide NOx emissions would be without the rules.

Estimating likely costs associated with this type of rulemaking is difficult and subject to numerous uncertainties. Attempting to calculate indirect costs (in this case, increases in the cost of electricity to residential, industrial and commercial customers and other indirect costs associated with a large scale undertaking such as this) is even more difficult especially in light of the ongoing deregulation of the utility industry, which is substantially changing how the power market functions. However, there are a few critical points to keep in mind.

First, historical experience with other major air pollution rules, the acid rain rules for example, shows that actual costs turn out to be less, sometimes significantly less, than were predicted by either industry or government during the rule development process. Industry groups estimated that the cost of reducing a ton of sulfur dioxide (SO_2) emissions under the traditional regulatory approach at about $1,500 per ton; EPA's estimate was about $650 per ton. The actual prices of an allowance (an allowance equals one ton of SO_2 emissions) available for purchase between 1993 and 1996 at the Chicago Board of Trade, where allowances are traded like commodities, fell from $122 to $66.[1] This disparity is due, at least in part, to the uncertainties inherent in trying to predict future costs and the fact that regulated facilities have been creative in finding cost effective ways to comply with requirements once they are in place.

Second, the reductions required from large utilities and industrial boilers are proposed to be accomplished through participation in a regional cap and trade program among all the states subject to the NOx SIP call. Electricity generating units (EGUs) and non-electricity generating units (non-EGUs) would be allocated allowances for tons of NOx that they are allowed to emit during the ozone season. IDEM will allocate NOx allowances for the affected units and owners or operators of these units will be able to buy, sell, or trade allowances, as necessary, to demonstrate compliance with the unit's NOx emissions cap. Because this program will be a regional program administered by U. S. EPA, sources will be able to buy, sell or trade allowances across state boundaries and between different types of units and sources.

Third, while the costs in terms of dollars spent is important, just as critical is the cost-effectiveness of this rule compared to other current or possible future clean air programs. The cost effectiveness of reasonably available control measures already implemented in Indiana, tend to be among the less expensive of available controls. Reformulated gasoline is the most expensive program with a cost effectiveness range from $3000 to $5000 per ton. U. S. EPA has determined that, in general, the cost effectiveness would be approximately $4,300 per ton of VOC or NOx removed for other potential programs. Some examples of these programs are vehicle emission testing, vapor control systems at gasoline pumps, and various industrial controls. IDEM believes that the NOx reductions required by this rule are among the most cost-effective measures available to achieve the air pollution improvement that is required by federal law.

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[1] Bryner, Gary C., Director Natural Resources Law Center, School of Law, University of Colorado "New Tools for Improving Government Regulation: An Assessment of Emission Trading and Other Market-Based Regulatory Tools", October 1999, page 15.

Lastly, it is important to take note of the costs that will be saved as a result of the air pollution improvements that will be achieved through this rule. Real savings will result from fewer work days lost to illness as well as from decreased health care expenses. The range of cost benefits of ozone and NOx reductions estimated by U. S. EPA for a health and welfare category that includes mortality, hospital admissions for all respiratory illnesses, and worker productivity losses, is $27 million to $1, 353 million in 1990 dollars nationally. The agriculture and forestry benefits are estimated to be between $260 million and $574 million, nationally, in 1990 dollars.[2] The air quality benefit of these rules is consistent with the federal NOx SIP Call and it is assumed that other states will reduce NOx emissions similarly.

Factors that may ultimately effect the estimated costs are:

- Selective catalytic reduction systems and selective noncatalytic reduction systems may work better or worse than expected.
- Availability of control and monitoring equipment and experienced labor.
- Future interest rates.
- Accuracy of data used to estimate projected emissions and allowances.
- Allowance availability and price
- Changes in the allowance allocation methodology that may change source specific allowances and may affect the costs.
- Percentage of allowances that are reserved for new sources and for energy efficiency/clean energy projects.
- Variations in some economic factors, such as discount rates and utility prices.
- Restructuring in the utility business sector.

II. Estimated Economic Impact on Regulated Entities

IDEM has spent considerable time and effort developing these cost estimates. The agency has consulted with other agencies (U.S. EPA, the Indiana Utility Regulatory Commission, the Indiana Office of the Utility Consumer, the State Utility Forecasting Group at Purdue University) and sought and received input from sources included in the draft rule on both IDEM's methodology and cost information for specific companies. The estimating methodology used in this analysis is a "study" estimate with ± 30% accuracy.

The estimated annual cost to regulated entities under these new rules would be associated with:

1. Initial capital costs for installing emission control and monitoring equipment.
2. Annual operation and maintenance costs.
3. Annual administrative costs (monitoring emissions, certifying compliance, modifying permits).

[2] IDEM's draft rule would achieve the vast majority of the air quality benefit of the federal rule, so comparable cost savings would be anticipated.

Utilities may recover some or all of these costs through a rate proceeding before the Indiana Utility Regulatory Commission.

A. Methodology to Estimate NOx Control Costs for Electric Generating Units (EGUs)

In order to estimate the NOx control costs to meet the proposed emission budget, the number of NOx controls necessary to achieve the needed emission reductions from baseline emissions was estimated. The needed emission reductions for each utility were estimated using its 2007 projected heat inputs and baseline emission rates equal to the lowest of the actual or the Title IV allowable emissions. Several assumptions related to the types of control equipment likely to be used and their efficiencies were made in addition to the assumptions that the proposed emission budget will be achieved using a regional cap and trade program.

The NOx emissions can be controlled mainly by two types of control methods, combustion modification controls and flue gas treatment controls. Combustion modification controls reduce NOx emissions by modifying combustion conditions such as combustion zone oxygen levels and temperatures and include low excess air, low NOx burners, over-fire air, and flue gas recirculation. However, not all of these control technologies are applicable to or effective in reducing NOx emissions from all boiler designs. Flue gas treatment controls, selective catalytic control systems (SCRs) and selective non-catalytic control systems (SNCRs), remove NOx emissions from the flue gas after it is formed by injecting ammonia or urea into the flue gas streams. Combustion controls and SNCRs are generally cheaper than SCRs.

In order to comply with the Title IV (acid rain) limits, utilities would have used most of the available combustion control options. A telephone survey of the utilities indicated that fuel switching (switching from combusting coal to gas, for example) is not likely to be an emissions reduction option. Therefore, the cost analysis assumed the application of SCRs and SNCRs. The cost estimate also considered the application of burner tuning and combustion optimization (combustion control measures which provide cheaper emission reductions) in addition to SCRs or SNCRs where utilities indicated that these controls could be applied to their units. Combustion control measures provide cheaper emission reductions and SNCRs are less expensive than SCRs, but SCRs are more efficient in reducing NOx emissions. SNCR experience on large units is very limited. It is generally cheaper on a dollar per ton of NOx removed basis to control high NOx emitting units (units with large capacities, high baseline emission rates, and high capacity factors). Therefore, cost estimates assumed controls on units that will yield a lower cost effectiveness ratio (costs of controls divided by the number of tons of NOx reduced).

The NOx control costs for electric generating units include total capital costs, fixed and variable operation and maintenance costs, and cost effectiveness in dollars per ton of NOx removed. A number of assumptions were made regarding the control equipment effectiveness, economic factors and retrofit requirements. The total ozone season costs are annualized capital costs plus fixed and variable operation and maintenance costs. The ozone season cost effectiveness in dollars per ton is equal to total ozone season costs divided by the total ozone season tons of NOx removed. The cost estimates are in 1998 dollars as most utilities provided cost estimates in 1998 dollars. It must be noted that at the time of these estimates, utilities were estimating the economic impact of U. S. EPA's NOx SIP Call on their facilities; while some estimates were based on rigorous engineering estimates (project control or definitive) and may be within ±10% margin of error, others were scope or order of magnitude estimates with ±20% to 30% margin of error. It is estimated that thirty two (32) selective catalytic reduction (SCR) system controls will be needed with an emission trading program (thirty seven (37) would be needed without trading). Thirteen (13) selective noncatalytic reduction (SNCR) system controls will be needed with an emissions trading program (fifteen (15) would be needed without trading). Ninety four (94) units are capable of generating greater than 25 Megawatts of electric output.

B. Estimated Costs for Electric Generating Units

The draft rule will reduce NOx emission from 156,419 tons of NOx per ozone season to 45,952 tons of NOx per ozone season from the following electricity steam generating unit companies:

American Electric Power	6 units*
Cinergy	27 units*
Hoosier Energy	4 units
Indiana-Kentucky Electric Company	6 units*
Indiana Municipal Power Agency	4 units*
Indianapolis Power & Light	17 units
Northern Indiana Public Service Company	17 units
Richmond Power & Light	2 units*
Southern Company	2 units
Southern Indiana Gas & Electric Company	9 units

*These companies have some units (25 out of 94) subject to requirements of a separate federal mandate (called the Section 126 rule) and must comply by May 1, 2003. Although IDEM's draft rule applies to these sources, the costs incurred by companies to comply with the Section 126 rule are a result of that federal mandate, not the state rule. In this fiscal impact analysis, IDEM presents the costs to all utilities.

These draft rules require NOx emissions monitoring using continuous emissions monitoring systems (CEMS) or alternative monitoring methods as applicable. A number of electric generating units presently monitor their NOx emissions using CEMS. No increase in monitoring costs at the existing CEMS units is assumed. No additional CEMS are assumed.

The cost estimates for each utility are based on the difference between its 2007 projected emissions and its estimated allowances under the 1995 to 1999 heat input scenario with 5% of allowances set aside for new sources and projected emissions estimates provided by the utilities. If the percentage of allowances set aside for new sources or any other purpose is increased, the cost effectiveness will increase. Indiana's draft rule allows unlimited trading across the SIP Call region.

Under the emissions trading program, utilities with cost effectiveness exceeding the allowance price are expected to buy allowances in order to reduce their NOx control costs and utilities with cost effectiveness below the allowance price are expected to sell allowances. U.S. EPA, in its regulatory impact analysis for the NOx SIP Call, federal implementation plan (FIP), and Section 126 petitions, estimated that the costs will be 2% lower if states meet their budgets by trading across the NOx SIP Call region instead of limiting trading within a state. In addition, emissions banking, starting from the start of the trading program will reduce the cost by 1% in 2007.

Table 1 presents estimated costs for each of the utilities subject to the rule. The first scenario presents the cost and cost effectiveness for each utility assuming companies can average within their own systems. Scenario #2 assumes trading between utilities and non-utilities in Indiana. Scenario #3 assumes trading between utilities and non-utilities within Indiana and regional trading for utilities. Scenario #3 is consistent with Indiana's draft rule. For all companies, cost effectiveness increases as the trading program broadens. It is important to note that of the 94 units subject to the state rule, 25 are also subject to the federal Section 126 mandate mentioned above. IDEM estimates that 17% of the total cost to comply with the state rule would be incurred in order for sources to comply with federal requirements. The summary of costs is as follows:

> Total capital cost = $1,396 million (This estimate may be higher or lower by 30%.)
> Total ozone season cost = $260 million
> Overall cost effectiveness = $2,291 per ton of NOx reduced.[3]

C. Methodology to Estimate NOx Control Costs for the Industrial, Commercial, and Institutional (ICI) Units

The estimated costs of the draft rules for the industrial, commercial, and institutional (ICI) units include the cost of NOx controls and the costs of measuring NOx emissions. The NOx control capital and operation and maintenance costs for the affected units were estimated using unit-specific data such as design heat input capacities and capacity factors. The capital costs were annualized using a control equipment life of ten (10) years and an amortization rate equal to 10%. The economic life of combustion modification controls is estimated at 10 years as compared to 15 to 20 years for flue gas treatment controls (SCRs and SNCRs). The total annualized capital costs and the ozone season operating and maintenance costs were used to estimate the cost per ton of NOx removed. U.S. EPA

[3]The U. S. EPA estimated average cost effectiveness in 1998 dollars is $1749 per ton of NOx reduced. IDEM's estimates are based on more specific information from Indiana sources.

estimates the annual cost of continuous emission monitoring equal to $32,300 in 1990 dollars.[4] The U. S. EPA "Alternative Control Techniques Document-NOx Emissions from Industrial/Commercial/Institutional Boilers", March 1994, was used to estimate costs. The costs in the U. S. EPA document are in 1992 dollars. The NOx control costs and emissions monitoring costs were adjusted to 1998 dollars using estimated 1990/1998 and 1992/1998 inflation factors equal to 1.16 and 1.114, respectively. The inflation factors were estimated using references such as Gross Domestic Product Implicit Price Deflator Index, Chemical Engineering Plant Cost Index, and Marshall & Swift Equipment Cost Index. The cost estimates do not include ICI units known to be shut down after 1996.

D. Estimated Costs for Industrial, Commercial, and Institutional Steam Generating Units

The draft rule establishes a budget equal to 13,847 tons for non-electric generating units (non-EGUs). The cost estimates are based, for each affected source, on the difference between its projected 2007 baseline NOx emissions and the estimated initial allowances for the years 2004 to 2006. These allocations and cost estimates assume 5% of NOx allowances are set aside for new sources.

There are ten known affected sources in this category. The allowances for these sources are based on the average of the two highest heat inputs in the five years 1995 to1999 and an emission rate equal to 0.17 pounds per million Btu. The affected sources are:

Alcoa
Amoco-Whiting
Bethlehem Steel
Inland Steel
Indianapolis Power & Light
LTV Steel
National Steel
New Energy Corporation
Purdue University
U. S. Steel

No costs have been estimated for shut down units.

The ICI sources will incur monitoring costs in the trading program. It is estimated that sixteen additional CEMs will be installed. One entity with six boilers and six stacks estimated that installation costs for continuous emission monitoring would be $1.5 million based on recent CEM experience with sinter

[4]Regulatory Impact Analysis for the NOx SIP Call, FIP, and Section 126 Petitions, Office of Air Quality Planning and Standards, Office of Atmospheric Programs, U. S. Environmental Protection Agency, September 1998, page 7-14.

plant CEMS and annual operating and maintenance costs of about $600,000 per year or $100,000 per CEM.

The costs of controls for ICIs will be higher if more than 5% of allowances are set a side for new sources or energy efficiency projects. Also, cost may be lower if allowances for emissions can be purchased for less than the cost of controls. Table 2 presents estimated costs for each of the ICI units subject to the rule.

Total capital cost = $21 million
Total ozone season cost = $4.8 million
Overall cost effectiveness = $1,321 to $1,940 ton per ton of NOx reduced.

The U. S. EPA estimated cost effectiveness in 1998 dollars is $1380 per ton of NOx reduced. If fewer allowances are given to ICIs, the costs will increase.

E. Methodology to Estimated NOx Control Costs for Cement Plants

In cement manufacturing, conditions favorable for formation of nitrogen oxides are reached routinely because of high process temperatures. Essentially all NOx emissions associated with cement manufacturing are generated in cement kilns during fuel combustion by two primary mechanisms:

- Oxidation of molecular nitrogen present in the combustion air which is termed “thermal NOx formation”.
- Oxidation of nitrogen compounds present in the fuel which is termed “fuel NOx formation”.

There are several control technologies (listed below) that can be applied to cement kilns to control NOx emissions. These process control systems include:

1. Cem Star (which involves the substitution of raw materials with steel slag)
2. Low NOx burners (LNB).
3. Mid-kiln firing.
4. Tire derived fuel.
5. SNCR.
6. SCR.

LNB is the technology that can be applied to all types of kilns and for this technology, extensive data were available in the U.S. EPA report. Therefore, to estimate the overall cost of the rule to the Indiana cement industry, LNB was chosen for cost analysis. The LNB installation requires an indirect-fired kiln firing system. An existing direct-fired kiln will have to be converted to an indirect-firing system for LNB installation, which would increase its retrofit cost.

Control costs will be incurred due to compliance with the emissions limitations, emissions measurements, and record keeping and reporting requirements. Sources can comply with the emission limitations requirements by one of the following methods.

(1) meeting the specified limits in the rule.

(2) installing low NOx burner or mid-kiln firing.

(3) installing an alternative control technology that will achieve a thirty percent (30%) emissions reductions.

All the above control options tend to achieve a thirty percent (30%) reduction in NOx emissions, therefore, this cost analysis is based on the application of control technologies that will achieve a thirty percent (30%) reduction in emissions. The sources can comply with the emissions measurement requirements by either installing a NOx continuous emissions monitor (CEM) or by performing an emission test once each ozone season.

The control cost includes the total of the control equipment capital, operation and maintenance costs (O&M), and administrative, emissions testing, record keeping and reporting cost. The capital and O&M costs were estimated from U.S. EPA's recent report for the cement industry, "NOx Control Technologies for the Cement Industry", Final Report, published in September 2000. This report updates U.S. EPA's 1994 Alternative Control Technology Document (ACT) for the cement industry and provides more recent data on emission control technologies and their costs. The costs in this report are in 1997 dollars. The emissions measurement, record keeping, and reporting costs were taken from U.S. EPA's fiscal impact analysis for the NOx SIP Call, federal implementation plan (FIP), and Section 126 petitions. These administrative costs are $63,705 per source (not per kiln) and were adjusted to 1997 dollars using a 1990/1997 inflation factor equal to 1.16.

F. Estimated Costs for Cement Plants

The proposed rule (326 IAC 10-3) will affect three (3) cement industries in Indiana with a total of eight (8) kilns. These companies are:

Essroc	4 kilns
Lehigh	3 kilns
Lone Star	1 kiln

The emissions reductions from the 2007 projected emission is 1,154 tons of NOx. As a permit requirement, two (2) kilns will be equipped with LNBs in 2001 and one (1) plant is presently equipped with LNB. Five (5) kilns currently have NOx CEMs, but these kilns will still incur the monitoring and reporting costs. The estimated total cost of controlling five (5) kilns including the control equipment capital and O&M costs and administrative costs to the three (3) industries from Table 3 are as follows:

Total capital cost: $2.8 million (indirect firing) to $5.7 million (direct-firing)
Total ozone season cost: $876,634 (indirect firing) to $1.4 million (direct-firing)
Overall cost effectiveness = $760/ton to $1,228/ton

The U. S. EPA estimated cost effectiveness in 1998 dollars is $1380 per ton of NOx reduced.

III. Summary

The estimated average cost effectiveness is $2,291 per ton of NOx reduced from electric generating units, $1,321 to $1,940 per ton of NOx reduced from industrial, commercial, and institutional steam generating units and $760 to $1228 per ton of NOx reduced for cement plants. IDEM estimates that 17% of the total cost will be incurred by the units subject to the federal Section 126 rule.

IV. Indirect Costs and Impact on Electric Rates

Indirect costs are impacts on sectors of the economy that interact with the electricity generating industry and other industries covered by the rule. Any project of this scope can be expected to have indirect costs. In this case, increases in electric rate are a likely cost. Households, fuel suppliers, industrial users of electricity, local taxpayers where sources are owned by local governments (schools or municipal combustion units) are subject to increased indirect costs. Indirect costs are not estimated in this document, but IDEM worked with the State Utility Forecast Group (SUFG) at Purdue University on estimating impacts on electricity rates. Supplemental model evaluations to the June, 2000 report, concludes that future average electricity retail rates would be expected to increase six (6) to seven (7) percent ($.0033 per kilowatt hour) if NOx emissions are reduced to 0.15 pounds per million Btu with a regional trading program. A residential bill for 500 kilowatt hours would increase by $1.65 per month.

Some positive indirect economic impacts can be expected from this rule. They would be associated with potential employment impacts (the rules will generate an initial demand for workers to install emission control technology and a continuous demand for workers to operate and maintain the technology), and business opportunities for companies that might be involved in assisting regulated sources with compliance activities.

V. Governmental Entities

There are no unfunded mandates placed upon any state or local agencies by this draft rule.

VI. Information Sources

Aerometric Information Retrieval System/AIRS Facility Subsystem (AIRS/AFS)
Alternative Control Techniques Document-NOx Emissions from Industrial/Commercial/Institutional Boilers, EPA-453/R-94-022, March 1994.
Alternative Control Techniques Document-NOx Emissions from Utility Boilers, EPA-453/R-94-023, March 1994.
Alternative Control Technique Document, NOx Emission from Cement Manufacturing EPA-453/R-94-004, March 1994.
Analyzing Electric Power Generation under the Clean Air Act, March 1998

Bryner, Gary C., Director Natural Resources Law Center, School of Law, University of Colorado "New Tools for Improving Government Regulation: An Assessment of Emission Trading and Other Market-Based Regulatory Tools", October 1999, page 15.
Chemical Engineering Plant Cost Index
Comment from company with ICI units
Electric Power Research Institute
Engineering studies provided by six utilities
Gross Domestic Product Implicit Price Deflator Index
Indiana Utility Regulatory Commission
Indiana Office of Consumer Counselor
Marshall & Swift Equipment Cost Index
NOx Control Technologies for the Cement Industry, EPA Final Report, September 2000.
Regulatory Impact Analysis for the NOx SIP Call, FIP, and Section 126 Petitions, Volume 1: Costs and Economic Impacts, EPA-452/R-98-003, September, 1998.
Regulatory Impact Analysis for the NOx SIP Call, FIP, and Section 126 Petitions, Volume 2: Health and Welfare Benefits, EPA-452/R-98-003, December 1998.
State Utility Forecasting Group at Purdue University

If you have any questions concerning this economic impact analysis, please contact Jean Beauchamp, Office of Air Management, Rules Development Section, at 232-8424.